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Docket Facility
U.S. Department of Transportation
Room PL-401,
400 Seventh Street
SW. Washington, DC 20590-0001

SUBJECT: Docket No. RSPA-99-6355

Pacific Gas and Electric Company (PG&E) would like to provide the following comments in response to RSPA's Request for Comment on Enhanced Safety and Environmental Protection for Gas Transmission and Hazardous Liquid Pipelines in High Consequence Areas (DOT Docket No. RSPA-99-6355; Notice 1). PG&E is an investor-owned utility providing natural gas and electric service to more than 12 million people in Northern and Central California. PG&E has over 5,600 miles of intrastate gas transmission pipelines.

PG&E supports efforts that will further assure the public about the safety and integrity of natural gas pipelines and will work with OPS and state regulators in this new initiative. We understand that OPS is seeking to validate each operator's systematic process for evaluating risks to pipeline systems in high consequence areas and before addressing the specific questions listed in the Federal Register notice, would like to take this opportunity to provide a brief overview of the approach taken by PG&E.

In addition to standards which implement pipeline safety regulations, PG&E utilizes a Geographic Information System (GIS) and a Pipeline Risk Management Program to continually improve system-wide operations and safety. PG&E's GIS contains the geographical location, pipe specifications, and the operating condition of its transmission pipelines. It also contains all the field reports of new construction, pipe condition and leaks. Our Pipeline Risk Management Program assesses the likelihood of failure due to mechanisms such as: third party damage, corrosion, and ground movement (including seismic hazards and major water crossings). It also assesses the consequences of failure in terms of impacts to the public, the environment, and to our business.

In the Federal Register notice, OPS has put out the following key elements for the process it envisions:

- The need for pipeline-specific assessments in determining the need for additional preventive and mitigative activities.
- The need to assess all risk factors and risk reduction activities in an integrated manner.
- The need for increased assurance that high consequence areas are being protected.

Keeping these key elements in mind, the following are PG&E's responses to selected questions asked under each of the process steps defined by OPS.

1. Identifying and Locating High Consequence Areas

a. How should "high consequence" areas be defined?

We support a definition which takes into account population density, environmental impact, and service impact. Examples of areas PG&E would consider to be high consequence areas are Class 4 locations, hospitals, schools, places of public assembly, apartment complexes, railroads, highways, airports, commercial/industrial buildings, navigable waterways, parks, and recreation areas, etc.

b. Should the operator or OPS be responsible for identifying the location of high consequence areas?

Due to the complexity of the issue, OPS should set general guidelines and require the operator to be responsible for identifying the location of high consequence areas.

e. What process should OPS or the industry use to ensure that the identified high consequence areas continue to reflect current conditions along the pipeline (e.g., population expansion, new information on environmental resources)?

Currently Code requires operators to monitor and record new construction and other changes occurring along the pipeline. This information is generally obtained from regularly scheduled patrols (foot and aerial), during development of drawings for new construction, and from special field surveys. PG&E posts this information routinely into GIS and utilizes that system to verify current conditions along the pipeline.

2. Identifying Affected Pipeline Segments

a. Does adequate data exist for operators to reliably ascertain the specific pipeline segments that could affect "high consequence" areas?

We believe adequate information exists. However, depending upon how "high consequence" areas are defined, operators may need to collect more data to accomplish this step.

b. Should pipeline segments near, but not within, high consequence areas also be examined for possible impact?

In identifying pipeline segments that could affect "high consequence" areas, we suggest that factors contributing to the likelihood of failure and/or factors impacting the consequences of failure of the high consequence line be considered. In short, we do not want any pipeline to fail, especially if it has any secondary impact on the high consequence area.

3. Inspecting and Assessing the Condition of the Affected Segments

a. Are the current industry standards sufficient for pipelines in "high consequence" areas?

Based on our experience, PG&E believes that current Code requirements and industry standards are sufficient, provided they are diligently applied by the pipeline operator. We also believe current requirements can, in certain instance, be overly conservative.

b. What is the current capability of smart pigs to find prior mechanical damage and other defects?

Regulations should not require operators to use smart pigs. At the present time, when a condition impacting pipeline integrity and public safety is identified by routine or non-routine maintenance, the pipeline operator is allowed to review the pipeline condition and choose the most cost-effective method(s) to assess/restore the structural integrity. The methods available to the operator could include smart pigging, if feasible given the pipeline geometry and other factors. This flexibility provided to the operator should not be withdrawn in favor of a mandate for use of smart pigs.

PG&E views smart pigs as one available tool for the assessment of pipeline condition. While smart pig technology has been utilized by PG&E, and current smart pig products reliably provide valuable information regarding pipeline corrosion damage, we can often determine critical pipeline conditions through other less costly means.

c. What alternatives to internal inspection can provide equivalent information on pipeline condition?

There are many other pipeline inspection methods available today. Each method identifies limited characteristic(s) of a pipeline and each method has an associated level of effectiveness. Examples of some other inspection methods include:

- *Video inspection which can detect interior corrosion, ovalization, buckles and dents,*
- *Close interval CP inspection which can ensure proper cathodic protection on pipelines*
- *X-ray which can detect defects in girth welds*

PG&E has found smart pigs to be effective at detecting pipeline corrosion. While smart pigs may be represented by manufacturers to be effective in many other measurements, our experience indicates that measurement of other pipeline characteristics by today's smart pig is both unreliable and less exact than other technologies.

d. How recently should a line have been pigged to provide reliable data for this step? What factors should be considered in making this determination (recent construction activity, cathodic protection system performance, interference from foreign line crossings, etc.)?

Many factors must be considered when establishing re-inspection intervals, including an analysis of the previous data relative to potential damage mechanism that have been identified. Re-inspection intervals should be left to the operator to establish.

e. How soon should the condition of a line be assessed after determining that it could impact a high consequence area?

After an operator has identified that a pipeline segment could impact a "high consequence" area, a comprehensive plan to assess the pipeline conditions should be immediately developed. The plan should include a historical review of existing data, assessment criteria, inspection method(s), implementation schedule, and cost. The plan should be implemented for the affected pipeline segment as soon as

practical, but the schedule will depend on a number of factors, including permit requirements, equipment availability, and operating requirements. For this reason PG&E believes operators should be allowed to set their own schedule .

f. What criteria should be used to identify anomalies that require further investigation?

We believe current industry standards are sufficient and should continue to be used as the criteria for identifying and evaluating anomalies.

g. What is the appropriate period between pig runs for high consequence areas? (Should this period be based on pipeline-specific conditions impacting the likelihood of corrosion or mechanical damage?)

Again, PG&E supports allowing operators the flexibility to use the inspection tool that is the most effective for the condition being evaluated. We support and encourage the adoption of a risk management approach to continually assess pipeline conditions and to determine appropriate inspection frequencies for specific pipeline segments. This approach would consider a number of factors including, corrosion, likelihood of third party damage, and ground movement.

h. Should OPS specify minimum performance criteria for internal inspection tools? If so, what should those criteria be?

The criteria should be developed collectively by OPS, operators and vendors.

4. Assessing the Need for Additional Preventative or Mitigative Actions

a. What structured assessment and decision processes could operators use to perform this step?

Operators should establish a comprehensive, integrated, segment-specific assessment program. We believe PG&E's Pipeline Risk Management Program is a good example of such a structured assessment.

b. What should be the criteria for deciding whether additional actions by the operator are required?

In determining additional actions, we recommend that actions be based on two factors: 1) Risk ranking - according to the Risk Management Program's evaluation and 2) a benefits to cost evaluation.

5. Remedying and Repairing the Affected Segments as Necessary

a. Should current industry standards be used as the repair criteria, or do other methodologies exist or need to be developed for pipelines in high consequence areas?

PG&E believes the current industry standards are sufficient, but is supportive of new technology developments and Code improvements.

b. What is the status of the current rulemaking to allow alternative repair techniques?

We welcome the recently issued final rule on Gas and Hazardous Pipeline Repair (RSPA-98-4733). The new rule will allow alternative repair techniques and encourage new repair technologies.

c. After an operator identifies anomalies requiring repair, how much time should be allowed in which to complete the repair work?

It will depend on the characteristics of the anomaly. If it has safety related consequences, it should be repaired as soon as conditions allow. If it has little or no impact on public or employee safety, the environment, or service reliability, the operator should be allowed to plan and schedule repair within a year.

6. Implementing and Monitoring Other Cost-Effective Risk Control Activities

a. How can operators monitor the effectiveness of risk control activities?

An annual report should be established that documents the risk management efforts and analyzes the incidents that have occurred. By analyzing incidents, Risk Management Program algorithms and the mitigation efforts taken to reduce risk can be validated and refined.

b. How would integrating an implementation schedule into normal operator maintenance schedules or budget cycles affect the cost of implementing these activities?

Integrating an implementation schedule into normal operator maintenance schedules or budget cycles will definitely save time and cost over treating it as a separate program.

7. Documenting Inspections, Assessments, and Actions

What would be the expected costs and labor burdens of these documentation requirements?

PG&E supports requiring operators to have thorough, accountable records of all steps identified in the operator's pipeline integrity and risk management program. If the process for high consequence areas outlined in this Federal Register notice is integrated into normal operator maintenance schedules, the cost and labor burden to meet these documentation requirements should be minimal.

8. OPS Reviews Operator Compliance

a. How can OPS ensure consistency of review across all companies?

We believe OPS or state regulators, as appropriate, should conduct an initial review of each operator's risk management or pipeline integrity programs and follow-up with regularly scheduled reviews, possibly to coincide with normal auditing schedules. The goal of these reviews should be to establish a cooperative working relationship between the operator and the regulating authority to ensure an effective and proactive safety program.

b. What review protocols or criteria will OPS use to evaluate the effectiveness of an operator's assessment and decision-making processes?

The effectiveness of an operator's risk management program should be measured by the safety performance of the pipelines by comparing with the operator's previous records and also industry statistics.

Thank you for the opportunity to comment.

Sincerely,

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Gas System Maintenance & Technical Support